# ProSteam - A Structured Approach to Steam System Improvement

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## Abstract

Optimal operation of site utility systems is becoming an increasingly important part of any successful business strategy as environmental, legislative and commercial pressures grow. A reliable steam model allows a clear understanding of the system and of any operational constraints. It can also be used to determine the true cost of improvement projects, relating any changes in steam demand back to purchased utilities (fuel, power, and make-up water) at the site boundary. Example projects could include improved insulation, better condensate return, increased process integration, new steam turbines or even the installation of gas-turbine based cogeneration. This approach allows sites to develop a staged implementation plan for both operational and capital investment projects in the utility system.

Steam system models can be taken one step further and linked to the site distributed control system (DCS) data to provide real-time balances and improve the operation of the system, providing an inexpensive but very effective optimizer. Such a model ensures that the steam system is set in the optimum manner to react to current utility demands, emissions regulations, equipment availability, fuel and power costs, etc. This optimization approach typically reduces day-to-day utility system operating costs by between 1-5 percent at no capital cost.

## Why Build a Steam System Model?

On many operating sites, maybe even the majority of sites, production is king and the steam system is regarded merely as a service that is far less important than the manufacturing processes themselves. Consequently, even companies that invest heavily in process modeling and simulation pay far less attention to the modeling of the steam system and, consequently, do not have the same understanding of the key players, the sensitivities and the interdependencies in this area.

Often, steam is assigned a unit value (dollars per thousand pounds) that serves to cover the perceived costs of operating the utility system when this value is apportioned across the various manufacturing cost centers. This value will, at best, represent an average cost of steam over a period of time and will often be inappropriate or downright misleading if used for evaluating potential projects.

A simple example would be a site that has a very close balance between suppliers and users at the low-pressure steam level. Site management is perhaps considering a new project to reduce the low-pressure steam demand. If the project is evaluated at the accountant's transfer figure of, say, $5 per thousand pounds it may appear that the project will pay back handsomely. In reality, however, the "saved" steam may simply be vented as it has nowhere else to go. The project will therefore save nothing at all and will even lead to the additional cost of lost water and heat in the vent.

A reliable model that reflects what actually happens within the steam system would identify the real cost of the project and avoid this inappropriate capital spend.

The above example is rather simplistic but no less valid for all its simplicity. In real life, the actual cost of low-pressure steam is likely to be variable. It may take on a finite value initially as the first amounts of steam are saved and then, at some point, the above situation applies and the value of low-pressure steam reverts to zero or even a negative value, as described. There may therefore be a specific limit to the amount of steam that can be saved and further investment would be fruitless. It is obviously good to know what this limit is! If a proper understanding of the real marginal steam and power costs is obtained, then the present inefficiencies in the system can be clearly identified and the correct investment decisions taken with confidence.

The true marginal cost of steam at any time and place in the system will depend on the actual path through which the steam passes on its way from generator to consumer. Medium- or low-pressure steam that is simply produced via letdown from the high-pressure boilers will have the same cost as the high-pressure steam. On the other hand, if the medium- or low-pressure steam is exhausted from a steam turbine, then the unit cost of that steam will be less than that of high-pressure steam because of the credit associated with the generation of shaftwork in the turbine.

Also, live steam for process use will have a higher value than the same steam used indirectly in heat exchangers because the latter can obtain credit for the condensate returned to the boilers.

Finally, the time of day is increasingly affecting the cost of steam as power tariffs become increasingly complex following deregulation of the electrical power industry.

Initial reasons for building a model of the steam system could, therefore, be:

- To calculate the real cost of steam under various operational scenarios
- To identify current energy losses
- To accurately evaluate project savings
- To forecast future steam demand versus production
- To identify the critical areas, sensitivities and bottlenecks within the system
- To identify no-cost operational improvements
- To evaluate tariffs and energy contract management
- To target and report emissions
- To form the basis of a consistent investment plan for the site

This paper will go on to show that many other benefits, including the optimization of steam system operation, can be obtained from such a model.

## WHAT TYPE OF MODEL IS AVAILABLE?

Many companies have made a good attempt at spreadsheet-based steam system modeling. Although these in-house models are invariably restricted to mass flow balances and flowrate-based power generation formulae, they represent a significant advance on nothing at all. They have the advantages of spreadsheet operation (flexibility, transparency) but are often limited by the spreadsheet skills of the utility engineer. Also, they cannot simultaneously reconcile mass *and* heat balances such as those required around deaerators. Perhaps their biggest drawback is that they are often only understood by the engineer who built them in the first place.

At the other end of the range is the full-blown process simulator, which is perfectly capable of modeling the utility system. The drawbacks in this case are the cost (large annual license fee) and the lack of transparency of the model. This is particularly important when changes and upgrades are required to be made to the model. The structure of the model may also be too rigid to allow rapid evaluation of a number of possible future scenarios.

A third type of model is that which looks and feels like a spreadsheet but, at the same time, has direct access to the whole range of steam and water properties through an add-in physical properties database. As well as taking advantage of all the benefits of spreadsheet operation, it yields a true simultaneous balance of mass, heat and power in the system. It also offers consistency between different users company-wide, and can be linked easily to the site's data historian for real-time calculations.

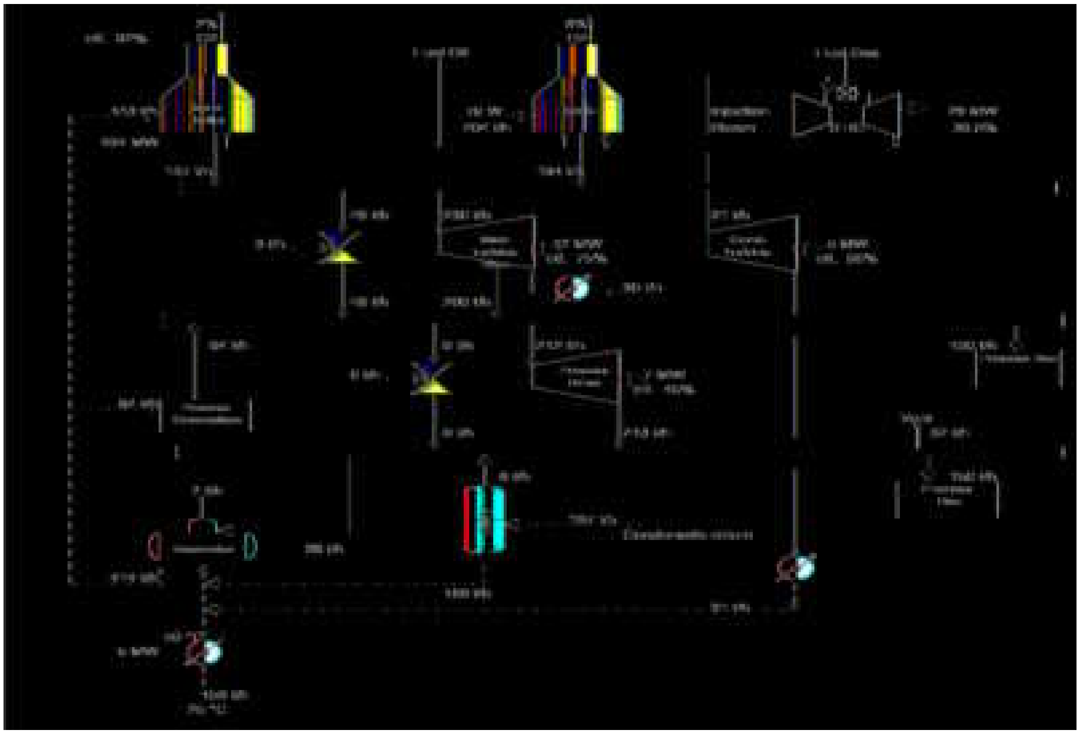
Good software packages in this category should also include drag and drop options for creating the utility flow diagram initially and pre-programmed equipment models to ensure that appropriate and consistent data are inputted and outputted around each equipment item and each header. Figure 1 illustrates a simplified model of a large site steam system including boilers, gas and steam turbines and three pressure levels of steam.

## HOW CAN I USE THE MODEL?

There are essentially two distinct types of model or model applications that are relevant to this paper; the planning model described earlier and an optimizer, which is constructed and used somewhat differently to the planning model. These are described below:

1. The planning model allows the engineer to evaluate potential projects, what-if scenarios and future production trends. Typically, this involves building the model with the conventional spreadsheet logic functions, e.g. "IF" statements, to replicate the way in which the plant control system operates. In this way, the model will simulate the present behavior of the system. This type of model can also be linked to the site data historian to produce real-time models and to flag up deviations from an optimum template. Such a model will generally contain two worksheets. The first is a top-down balance based upon plant readings (which is usually more reliable at the high-pressure level) and the second is a bottom-up balance based upon the actual process demands. This allows the actual steam balance at any time (the top-down model) to be compared to an ideal template (bottom-

**Figure 1: Typical Site Steam Model**



up model) for that mode of process operation/steam demand. Differences can be highlighted and the appropriate action taken by the operator.

2. An optimizer model which will identify the least cost mode of utility plant operation under different scenarios (production rates, power tariffs, etc). This differs from the planning model in that it automatically switches equipment items on and off within the model to arrive at the true optimum. Depending on the number of degrees of freedom in operating the system (alternate drives for rotating equipment, choice of different equipment items, let-downs and vents), the model is capable of saving between 1-5 percent of utility cost at zero capital cost. Simple models can use Microsoft Solver to identify the optimum settings for the system whereas more powerful, advanced solvers are needed for more complex problems. This type of model is often used on-line at the control room level to improve hour-by-hour operation. Equally, it can be used off-line for management to pre-determine how best to operate the utility system under future planned conditions (for example, on a weekly basis tied to anticipated production, time of year and time of day power tariffs).

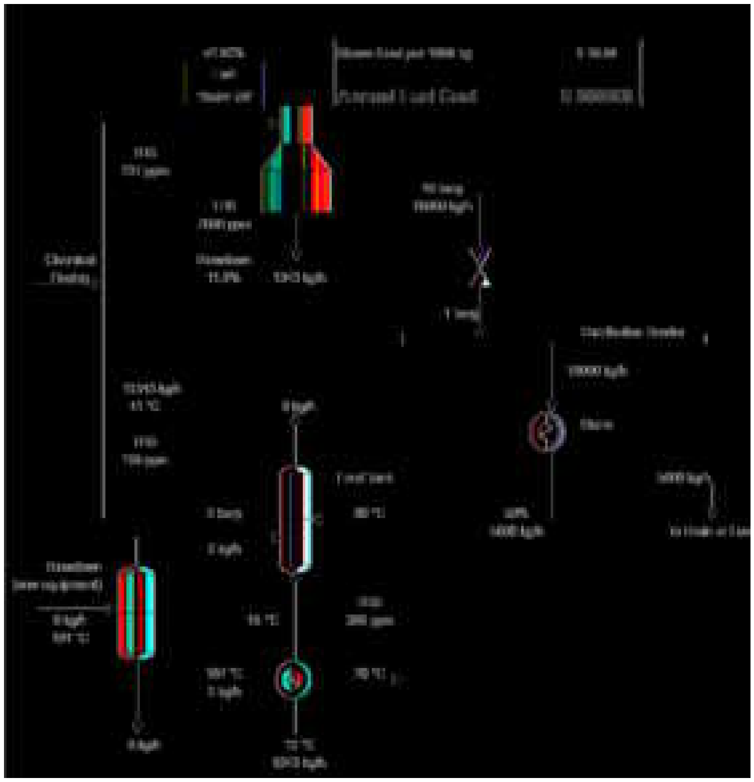
Figure 2 illustrates the first option, for off-line project planning.

This is a simple, single level steam system with several potential projects already incorporated but deactivated in the base case. It indicates that the base case operation costs $600,000 per year in terms of fuel and water. Potential projects that can quickly be investigated with this model include:

- Improved condensate return (from 50-80 percent);
- Increased allowable TDS through continuous blowdown control;
- Blowdown flash steam recovery;
- Boiler blowdown to pre-heat boiler feedwater; and
- Boiler efficiency improvement (from 80- 85 percent).

The model allows any or all of these modifications to be calculated by simply ticking the box alongside the project in the table at the right hand side of the spreadsheet. Figure 3 shows that incorporating ALL of the potential projects will reduce the annual operating cost to $483,900, a saving of $116,100 per year, or almost 20 percent.

## Figure 2: Base Case (Existing) Steam Balance



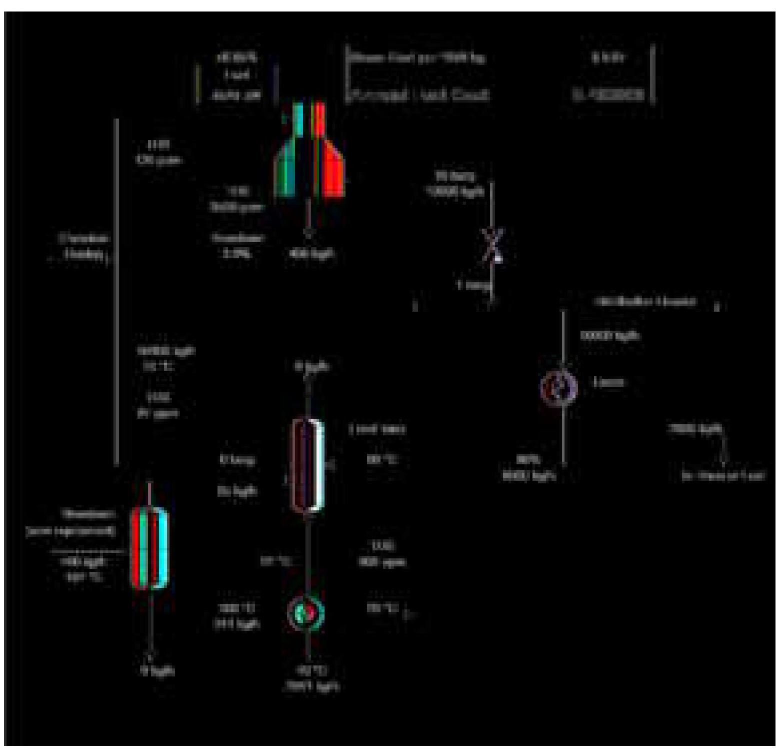
**Base Case Parameters**

| | |
|---|---|
| Steam Generation Pressure | 10 barg |
| Header Pressure | 1 barg |
| Steam Demand | 10000 kg/h |
| Boiler Efficiency | 80% |
| Boiler TDS Level | 2000 ppm |
| Condensate Return | 50% |
| Condensate Temperature | 80 °C |
| Make-Up Water Temperature | 10 °C |
| Make-Up TDS Level | 300 ppm |
| Feed Tank Pressure | 0 barg |
| Dosing TDS Increase | 69 ppm |
| Operation | 6000 h/y |
| Fuel Cost | 9.47 $/MWh |

**Potential Improvement Projects**

| | | |
|---|---|---|
| Condensate Return | 80% | ☐ |
| Allowable TDS | 3500 ppm | ☐ |
| Blowdown Flash | 0 barg | ☐ |
| Blowdown HX | 10 °C approach | ☐ |
| Boiler Efficiency | 85% | ☐ |

## Figure 3: Steam Balance After Inclusion of Projects



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**Potential projects ticked**

The value of the model here is demonstrated by the fact that it is assessing the interactions between the projects to arrive at the true saving. If the project savings were calculated individually for each project, the sum of the savings would appear to be greater than $116,100 per year because some of these projects are competing for the same energy saving. The model therefore allows us to calculate the true, cumulative savings and, importantly, to draw up a plan of staged investment so that the projects can be ranked in order of attractiveness and form the basis of a coherent investment plan.

The above use of a steam model is typical of the off-line, planning application. It essentially tells us how the system will react to certain future operational scenarios whether they are future projects, new process demands or new energy prices. The model is essentially operating as a simulator to reflect the behavior of the system as it is presently configured.

If there are a number of degrees of freedom available to the utility system operator (steam turbine or electric motor drive, variable load turbo-generators, or even intentional steam venting), then a model can be constructed that doesn't simply predict the behavior of the existing system in a particular configuration but actually tells us which is the optimum system configuration we should be employing. This is referred to in this paper as the optimizer model.

Figure 4 illustrates a simple system with some basic degrees of operational freedom.

It shows a utility system that contains a process drive (500kW) that can be either an electric motor or condensing turbine, a variable extraction/condensing turbo-generator and the ability to vent low-pressure steam. The base case operation shown here is for a power-to-heat ratio of 4:1. In other words, a megawatt of purchased electrical power costs four times as much as a megawatt of fuel. Under these conditions, the optimum process drive is the electric motor and condensing in the main turbo-generator should be zero. In reality, it may not be possible to reduce the condensing flow to zero for mechanical reasons—this is simply an illustration. Hourly cost of operation is calculated to be 54.2 cost units per hour.

Now consider the possibility of the power:heat cost ratio increasing to a value of 6:1, perhaps because of high electricity costs at particular times of day (time-of-day tariff). Under these conditions, we can input the figure of 6:1 and press the optimizer button in the model. Figure 5 illustrates the input/output screen of the model.

This immediately flags up operator instructions to switch on the condensing section of the turbo-generator and to switch to the steam turbine process drive. We are presented with the flow diagram in Figure 6 which indicates an hourly cost

**Figure 4: Base Case Operation**

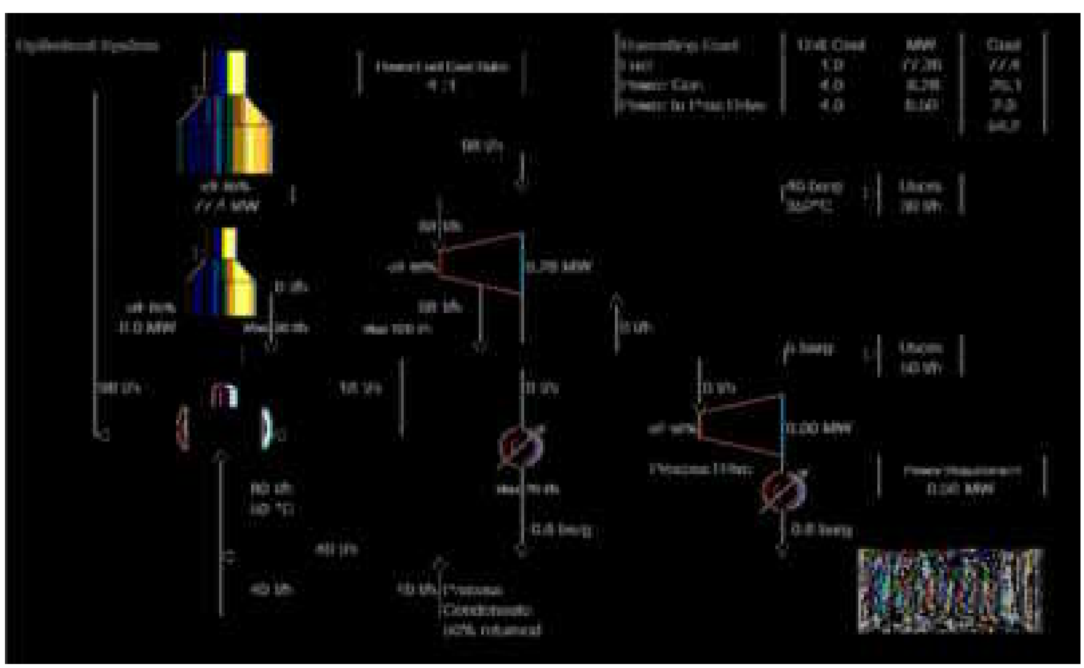


**Figure 5: Operator's Screen**

**1. Enter Current Operating Parameters**

| | |
|---|---|
| Operate LP Boiler | 0 |
| Main Turbine Condensing Section | 0 |
| Process Drive using Steam | 0 |
| Deliberate Venting | 0 |

(0=Off, 1=On)

| Cost Ratio Power:Fuel |
|---|
| 6 :1 |

MWe:MW fired

New Electricity Price

**2. Run Optimiser**

**3. View Optimisation Report**

**Operating Costs**

| | |
|---|---|
| Current | 42.69 |
| Optimised | 36.24 |
| **Saving** | **15.1%** |

Potential Savings by Changing Operation

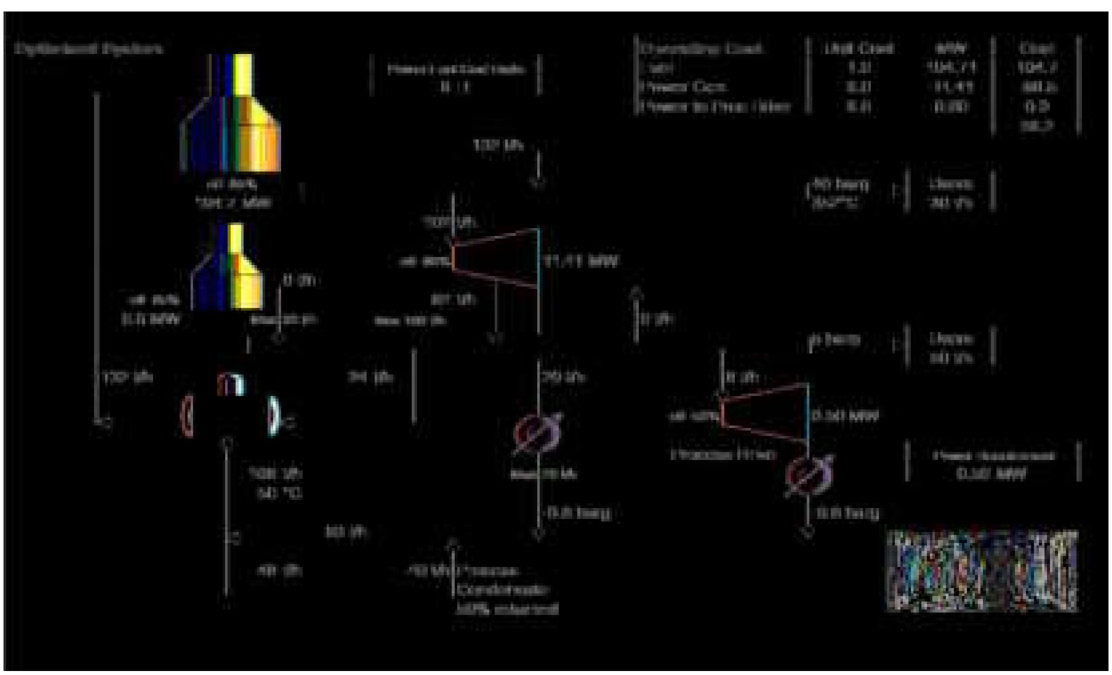
| Equipment Operation | Current | Optimised | Change? |
|---|---|---|---|
| Operate LP Boiler | Off | Off | **No Change** |
| Main Turbine Condensing Section | Off | On | **Change Required** |
| Process Drive using Steam | Off | On | **Change Required** |
| Deliberate Venting | Off | Off | **No Change** |

Operator Actions

of 36.2 cost units which compares favorably with the value of 42.7 which would be the case if the operator action were not taken, a saving of 15%. This simple example illustrates the additional functionality of the optimizer model over the planning model. Whereas the planning model allows us to assess the effect of project and process changes on the existing configuration of the steam system, the optimizer model allows us to be proactive in determining the best configuration of the steam system under present or future operating scenarios.

A planning model in the above example would have evaluated the savings we could obtain under the base case configuration and this would be the

**Figure 6: Optimum Operations at an Increased Power Cost**



value shown in Figure 5 as "current operating costs" (42.7 cost units compared to the base case cost of 54.2 in Figure 4). The optimizer has taken this a step further and identified even lower operating costs (36.2 cost units) by suggesting changes to the configuration of the steam system as indicated.

## Industrial Case Study

Linnhoff March has built more than 100 steam system models in recent years and all of them have identified ways in which a system can be improved, either operationally or through capital projects. Many of these models have been created for large oil refineries of which the following is a typical example.

Figure 7 shows a simplified drawing of a UK oil refinery steam system.

The refinery low-pressure steam system contains two separate sections. Due to site expansions, one element of the low-pressure system was in deficit and pulling large amounts of steam down from a much higher pressure. The other element of the low-pressure system was in surplus with regular venting of excess steam to atmosphere.

The almost trivial (in retrospect) solution of connecting the two elements of the low-pressure system considerably improved the overall steam balance (Figure 8). The relatively short crossover connection paid back within a matter of weeks.

Because of the complexity of operations on the site, plant personnel had not previously spotted this opportunity and it probably is not an isolated example. Building a model of the overall steam system for the first time allowed a consistent analysis to be carried out of the whole system rather than simply rely on local, ad-hoc improvements.

This type of modeling has been applied by Linnhoff March in over 100 site applications and operational savings of between 1-5 percent have been achieved. When added to the benefits of capital project savings identified by the planning model, total energy savings regularly amount to 15 percent.

## Benefits

Many of the benefits of an accurate site steam model have already been described in this paper.

To summarize, off-line planning models provide the following benefits:

- Improved utility cost accounting
- More reliable project screening
- Enhanced understanding of the steam system through the identification of key controllable parameters
- Better contract management of purchased utilities (fuels, electricity)
- Identification of no-cost operational improvements
- Reliable reporting of emissions
- Utilities configuration planning (daily, weekly, monthly)

**Figure 7: Existing Refinery Steam Balance**

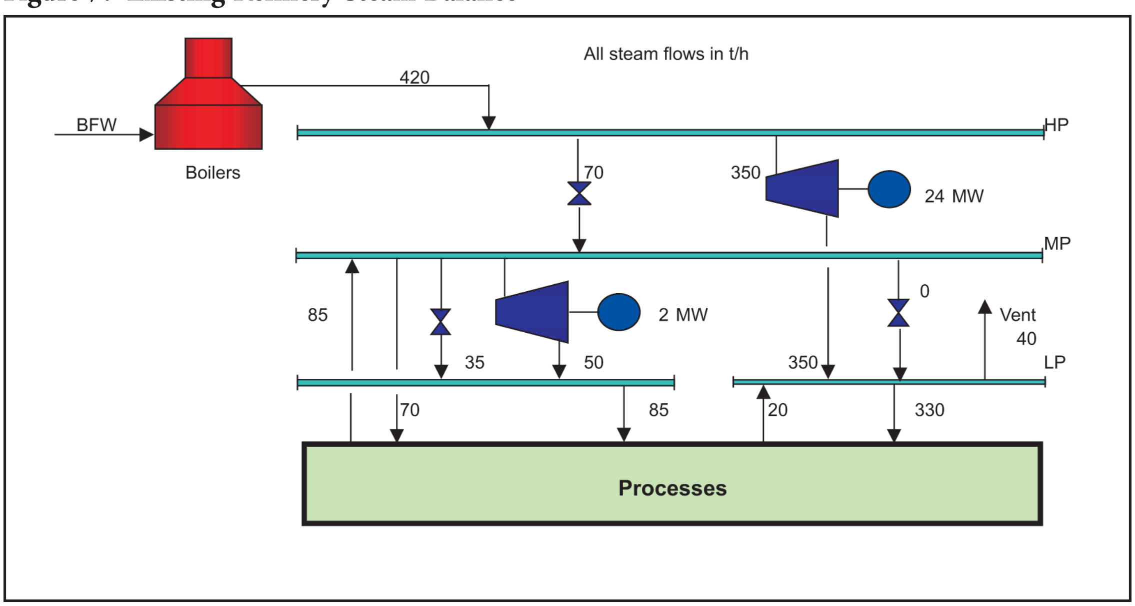
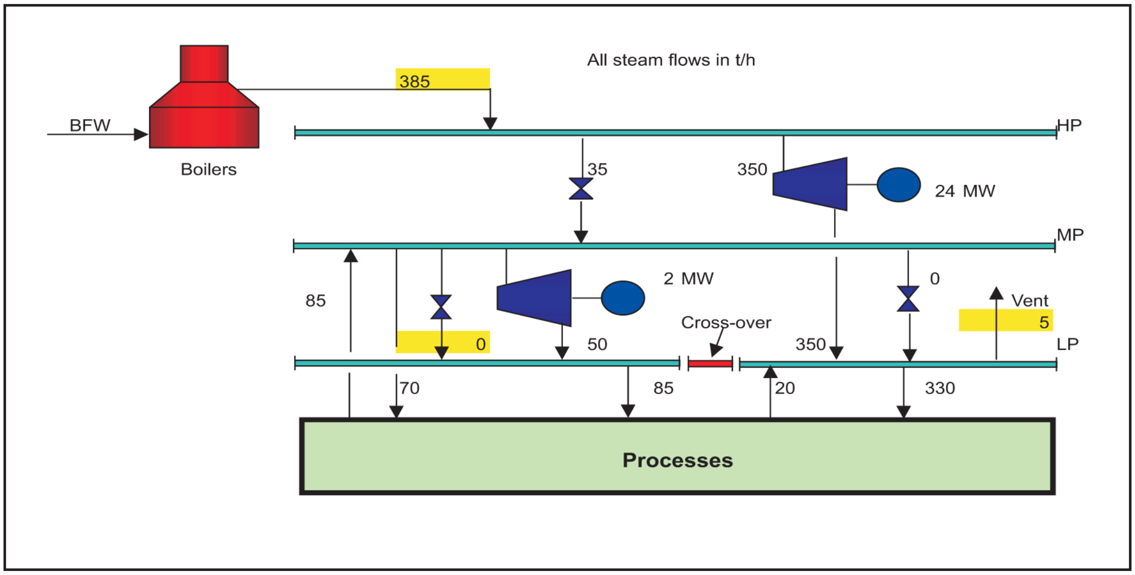


**Figure 8: Improved Refinery Steam Balance**




■ Basis for strategic investment "RoadMaps"
On-line (open loop) systems can offer further benefits:

- Data validation and reconciliation
- Optimized utility system operation (hourly or daily basis)
- Plant performance monitoring

Cumulatively, these benefits can save 15 percent of current utility costs. This figure, of course, is somewhat dependent on the starting point for improvement, i.e., the current state of understanding of the system. Even from a relatively sophisticated starting point, we have seen no-cost savings of five percent in systems with six or more degrees of operational freedom.

## Conclusions

Spreadsheet-based steam system models with a built-in physical properties database are a very cost-effective way of reducing the operating cost of steam generation and distribution and forming a consistent basis for future investment strategies.

The cost of building an off-line planning model will range from less than $10,000 for a simple, single steam level system up to $25,000 or more for a typical oil refinery or petrochemical complex. Converting such a base model to an on-line optimizer will roughly double the cost of the model. The cost of the actual software package on which the model is based is only a tiny fraction of the above costs.

Since potential benefits can be several million dollars per year on a large, complex site these models will pay back in a matter of weeks, if not days.

Such tools should be more widely adopted by industry for improved energy cost accounting and reduced operating costs with attendant reduction in the emission of greenhouse gases to the environment.

## References

1. JD Kumana, "Use Spreadsheet-Based CHP Models to Identify and Evaluate Energy Cost Reduction Opportunities in Industrial Plants", 23rd IETC, Houston, May 2001.

## Appendix

ProSteam™ by Linnhoff March provides a number of pre-formatted plant equipment models for setting up site utility simulations. The model functions currently available are:

*Steam Turbines*

| | |
|---|---|
| Trbn_A | Single-Stage Steam Turbine model (Mass flowrate specified). |
| Trbn_B | Single-stage Steam Turbine model (Power generation specified). |
| Trbn_A2 | Two-Stage Steam Turbine model (Mass flowrate specified). |
| Trbn_B2 | Two-Stage Steam Turbine model (Power generation specified) |

| | |
|---|---|
| Trbn_A3 | Three-Stage Steam Turbine model (Mass flowrate specified) |
| Trbn_B3 | Three-Stage Steam Turbine model (Power generation specified) |

*Heat Exchangers*

| | |
|---|---|
| HtExchngr_A | Water/Steam heat exchanger based on fluid conditions |
| HtExchngr_B | Water/Steam heat exchanger based on duty |
| HX_Process To Process | Process/Process heat exchanger U, A, Nshells & Cp specified |
| HX_UA_ Exchanger | UA based heat exchanger - U,A, LMTD & Ft specified |
| HX_BFW Heater | UA Boiler feed water heater (Process/Water exchanger) |
| HX_Steam Generator | Steam Generator (process/water-steam heat exchanger) |
| HX_Ft | Exchanger Ft factor |
| HX_LMTD | Exchanger LMDT |
| HX_NoShells | Exchanger - Number of Shells |
| HX_UA | Exchanger UA (also Ft and LMTD) |
| HX_FlowFactor | Flow Adjustment Factor - for heat transfer coefficient |
| Calc_Cp | Specific Heat Capacity calculation |
| Calc_CpMean | Specific Heat Capacity (Mean) calculation |

*Gas Turbines*

| | |
|---|---|
| GTurb_A | Gas turbine model |
| GTurb_B | Gas Turbine with varying air temperature or injection steam conditions |

*Fuels*

| | |
|---|---|
| Fuel LHV | Fuel Lower Heating Value |
| Fuel Name | Fuel Name |
| Fuel Descr | Fuel Description |

*Boilers*

| | |
|---|---|
| Blr_A | Simple Boiler model. (A) |
| Blr_B | Simple Boiler model. (B) with firing efficiency. |
| Blr_C | Advanced Boiler model with emissions calculations. |

*Compressors*

| | |
|---|---|
| ThermoComp_A | Thermocompressor – Rating model. |
| ThermoComp_B | Thermocompressor – Design model. |
| Cmprssr_A | Single-Stage Compressor model (Mass flowrate specified). |
| Cmprssr_B | Single -Stage Compressor model (Power specified). |
| Cmprssr_A2 | Two-Stage Compressor model (Mass flowrate specified). |
| Cmprssr_B2 | Two-Stage Compressor model (Power specified). |

*Miscellaneous*

| | |
|---|---|
| Drtr_A | Deaerator model. |
| DSprHtr_A | De-superheater model (Inlet Steam Flowrate Specified). |
| DSprHtr_B | De-superheater model (Outlet Steam Flowrate Specified). |
| FlshVssl_A | Flash Vessel model. |
| WaterPump_A | Water Pump Model |
| LtDwnVlv_A | Let-down Valve model. |